

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Investigation by the Department of Telecommunications)	
and Energy on its own motion to investigate the)	
appropriateness of the use of Risk Management Techniques)	D.T.E. 01-100
to Mitigate Natural Gas Price Volatility.)	

Initial Comments of AllEnergy Gas & Electric Marketing Company, L.L.C., SCASCO Inc., Amerada Hess Corporation, Select Energy, The National Energy Marketers Association and The New Power Company, collectively, the “Competitive Suppliers”

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EXECUTIVE SUMMARY

AllEnergy Gas & Electric Marketing Company, L.L.C., Amerada Hess Corporation, SCASCO Inc., Select Energy, The National Energy Marketers Association and The New Power Company, collectively, the “Competitive Suppliers” believe there should be four basic principles applicable to any Utility Risk Management Program, “URMP”.

1. URMPs should not distort price signals to customers.

One of the guiding principles of utility rate design continues to be that rates should be reflective of the proper price signals. URMPs have the potential of distorting those price signals if allowed to be used for more than short-term gas purchasing strategies. URMPs should be limited in term to the next six month CGA period, and should be limited in quantity to pipeline commodity resources adjusted downward to reflect warm weather and high migration scenarios.

2. Utility resource planning objectives should continue to provide for least-cost service.

This principle has served utility customers well, and should not be confused by other co-objectives related to rate stability.

3. A URMP should not adversely impact the competitive market.

URMPs that change the utility’s neutrality as to whether or not a customer chooses a competitive supplier should not be allowed. Absent this indifference, a program will be exposed to all of the vagaries inherent in unregulated monopoly power. LDCs should not be allowed to receive incentives for gas procurement, nor should URMPs be the basis for LDCs to offer products other than default service

4. Any costs of a URMP should be included immediately in the utility Cost of Gas Adjustment so as to reflect the appropriate cost to compare for customers.

This cost recovery treatment provides a level playing field between the utility and suppliers who are competing for the utility’s customers.

INITIAL COMMENTS OF COMPETITIVE SUPPLIERS REGARDING THE IMPACT OF UTILITY RISK MANAGEMENT PROGRAMS ON THE COMPETITIVE MARKET

I. INTRODUCTION

AllEnergy Gas & Electric Marketing Company, L.L.C., Amerada Hess Corporation, SCASCO Inc., Select Energy, The National Energy Marketers Association, and The New Power Company, collectively, the “Competitive Suppliers”¹, appreciate the opportunity to provide comments in this proceeding. A change in utility gas procurement policy could have a profound and potentially devastating effect on the Massachusetts competitive market if it is not carefully crafted. The Competitive Suppliers proffer their comments below and also respond to the applicable questions posed by the Department in its NOI.

II. PRINCIPLES FOR A UTILITY RISK MANAGEMENT PROGRAM

The Competitive Suppliers believe there should be four basic principles applicable to any Utility Risk Management Program, “URMP”.

1. URMPs should not distort price signals to customers.

One of the guiding principles of utility rate design continues to be that rates should be reflective of the proper price signals. URMPs have the potential of distorting those price signals if allowed to be used for more than short-term gas purchasing strategies.

2. Utility resource planning objectives should continue to provide for least-cost service.

This principle has served utility customers well, and should not be confused by other co-objectives related to rate stability.

3. A URMP should not adversely impact the competitive market.

URMPs that change the utility’s neutrality as to whether or not a customer chooses a competitive supplier should not be allowed. Absent this indifference, a program will be exposed to all of the vagaries inherent in unregulated monopoly power.

¹ Please see APPENDIX 1 for a description of each organization.

4. Any costs of a URMP should be included immediately in the utility Cost of Gas Adjustment so as to reflect the appropriate cost to compare for customers.

This also provides a level playing field between the utility and suppliers who are competing for the utility's customers.

We will elaborate on each of these principles below.

1. Gas pricing mechanisms should reflect market price signals.

The Competitive Suppliers believe the Department should look to the Electric Restructuring Legislation and its own Order with respect to Default Service for guidance with respect to natural gas default service pricing policy.

Chapter 164, section 193(1B)(d) of the restructuring act provides in pertinent part

... that the default service rate so procured shall not exceed the average monthly market price of electricity.”

...that bids to supply default service "shall include payment options with rates that remain uniform for periods of *up to six months*." [Emphasis added]

The legislature clearly intended for electric default service to reflect the short-term market price of electricity and to give customers appropriate price signals. The legislature also allowed for a smoothing of prices by allowing up to a six-month payment option. This is similar to the way gas utilities in Massachusetts recover gas costs. Gas costs are recovered over two six month seasons through the Cost of Gas Adjustment Clause. Gas costs have been fully unbundled from each utility's base rates. The six-month CGA periods would appear to provide a reasonable limit for hedging activity. Utilities could be allowed, but not required, to use risk management tools for the upcoming six month CGA period, but no longer.

If utilities are allowed to lock in prices further out into the future, price signals could be distorted. The further into the future that prices are locked in, the less likely they are to reflect market prices. One of the Department's long-standing principles for rate design is to provide

accurate price signals. Risk management tools employed by the LDC may be inconsistent with that objective.

The Cost of Gas Adjustment Clause provides for a considerable amount of rate stability already. Furthermore, most LDCs offer budget billing to at least their residential customers. Budget billing levelizes bill payment amounts over twelve months. CGA rates typically change only once every 6 months. This offers considerably more stability than other jurisdictions where PGAs change monthly. Inventory gas in underground storage and peaking facilities also provide a considerable amount of winter price stability since they make up approximately 60% of the peak day gas usage. Additionally, most of the LDCs in Massachusetts purchase a significant percentage of city gate supply at a fixed price. Seasonal reconciliation of deferred gas costs allows for an orderly collection/return of under/over collections over a future six-month period. Do Massachusetts' consumers need stability beyond these six-month periods? The Competitive Suppliers believe that attaining this additional stability could expose sales service customers to considerable risks, as explained below.

If utilities had locked in prices for this winter last summer, we would not have seen the reductions in peak CGAs that were recently filed and approved by the Department. As the winter has progressed, it has proven to be a warm one across the country. Underground storage continues to be very nearly full. In addition, demand has been slack due to the downturn in the economy. Consequently, commodity prices have fallen considerably since last summer and Massachusetts' customers have seen the benefits of those falling prices. Had the utilities locked in the prices available last summer, which seemed like a bargain compared to last winter's record-setting prices, consumers would not have seen decreases in peak CGAs. Even with CGAs

at inflated levels, we would probably **still** be looking at large deferred gas cost balances due to lower volumes failing to recover fixed capacity costs.

On the other hand, if LDCs had locked in prices for this winter last summer and market prices had gone up sharply, they could have faced a number of customers whose competitive market contracts had expired returning to sales service in search of lower prices. Unless the volume of gas hedged by the LDC was substantially higher than the requirements of the customers it was serving prior to the mass migration, it would be forced back out into the market to purchase supply at prices sharply higher than those reflected in its CGA. The LDC would either have to raise CGA rates mid-cycle or carry a large deferral balance into the next winter season, either of which would defeat the purpose of hedging. The only alternative would be for the LDC to turn away these customers, leaving them angry and disaffected.

2. Utility resource planning objectives should continue to provide for least-cost service.

LDC resource planning objectives have historically been to provide least-cost service. Ratemaking objectives have also included an objective for continuity, which means that bill impacts should be kept to a reasonable level. This does not mean however that this objective should override that of least cost planning. If there are two objectives that are not necessarily consistent with each other, how is the Department going to determine prudence in the case where an LDC follows one objective to the detriment of the other? The Department should make it clear that least-cost planning remains the primary objective.

3. A URMP should not adversely impact the competitive market.

A URMP should not be allowed to be an impediment to the competitive market. If LDCs hedge 100% of their portfolios and market prices fall, the migration of customers to third-party suppliers that would most likely occur would leave the utility holding over-priced gas supplies

for which it has no demand. It would then need to sell these supplies into the market at a loss, which would become part of a deferral balance that the utility would be required to underwrite until the next year's true-up. The utility can hardly be completely impartial to a customer's choice of supplier if every customer who migrates contributes to an increasing liability on its balance sheet. If hedging is allowed, it must include limits that continue to promote neutrality for the LDC as to whether or not a customer switches to the competitive market.

Along those lines, LDCs should in no way be offered incentives for gas procurement. The competitive market is functioning well in the commercial and industrial sectors. If competition is to develop in the residential sector, suppliers need not face a competitor that, in addition to the benefit of incumbency, has less risk and a greater opportunity to earn a return on its product. LDCs have had a longstanding monopoly obligation to provide least cost service and pass along merchant costs at cost to the customer. In return, they are allowed to fully recover all costs. If LDCs want to compete in the competitive market, they are free to form unregulated affiliates who will take on the risks as well as the rewards of any such program.

A URMP should not be the basis to offer a product other than default service. Alternative products and services should only be offered in the competitive market, including all of the risks inherent in the competitive market. LDCs should only be providing default service, and should not be allowed to offer fixed price products, or any other product in addition to default service. Any utility that believes it can make a profit in that type of business should form an unregulated affiliate to compete fairly with other suppliers of like products.

4. Any costs of a URMP should be included immediately in the utility Cost of Gas Adjustment so as to reflect the appropriate cost to compare for customers.

All costs of a URMP should be included in the LDC's merchant costs. These are clearly costs associated with providing merchant service, and should therefore be recovered in the

LDC's CGA. If URMPs are approved by the Department, and because these costs can be significant, they should be estimated and included in the LDCs' next pro-forma CGA calculation. This would include all administrative costs, systems costs and personnel costs, as well as the costs of hedging, such as financial instruments. They should be included on an embedded basis, in the same way as gas supply procurements. The Department should not wait until the LDC's next base rate case, which could be several years away. These costs must be reflected in the CGA since it is the price against which competitive suppliers compete.

In addition to cost-causality principles, there is one other important reason why the Department should require LDCs to identify administrative costs associated with URMPs and include these costs in the CGA. URMPs represent a fundamental change to the way the LDCs administer default service. Implementing that change requires resources and those resources cost money. If the Department allows the LDCs to implement URMPs without recovering their administrative costs through the CGA, it is The Competitive Suppliers' fear that the LDCs will simply "borrow" administrative resources from other areas, including their transportation programs. It would be unfortunate if the quality of service provided to transportation customers were diminished to implement a program directly solely at sales customers.

III. RESPONSES TO THE DEPARTMENT'S QUESTIONS

1. *Should Massachusetts gas utilities be allowed or required to implement a risk-management program to mitigate price volatility for gas customers?*

The Department could allow LDCs to use risk management tools for the upcoming six month CGA period, but no longer. This could allow LDCs to lock in prices used to forecast CGAs and limit some of the price volatility that would cause price related over or under collections. However, in winters such as this one, if weather warms

up and demand and prices go down, LDCs would then forego that benefit for their customers.

2. *How will risk-management by LDCs affect gas unbundling and customer choice in Massachusetts?*

The impact of risk-management on gas unbundling and customer choice depends upon the design of the program. If the program is limited to locking in prices for the next six month CGA period, the impact may be limited. If LDCs are able to lock in long-term futures contracts, it could produce significant unintended consequences for the competitive market. There is likely to be a divergence between the price paid in advance for a long-term strip and the actual market price for gas at the time of delivery. If an LDC buys a 3-year strip for the majority of its load, and market prices go up substantially after 6 months or 1 or 2 years, it effectively shuts down the competitive market during that timeframe. Conversely, if market prices go down, it provides a significant rate arbitrage opportunity for suppliers and migration is likely to accelerate. Costs of high priced hedges must then be borne by the remaining sales customers. In such a case, the utility would then be incented to try and keep its customer base and start implementing rules as to when customers may or may not switch.

Competitive Suppliers have long advocated LDC default prices that reflect the market price of gas. LDC prices serve as the “cost to compare” for customers who are shopping in the competitive market. Out-of-market commodity costs have created situations where suppliers are shut out of the market for a period of time because of the lag between the time that market prices go up and LDC prices reflect market price

changes. Similar situations could occur if LDCs are allowed to purchase long-term futures contracts.

3. *Should gas utilities be limited to specific types of risk-management instruments? If so, what types?*

4. *Should there be a percentage volume of gas that LDCs would be allowed to hedge?*

The Competitive Suppliers believe that LDCs should not only be limited to hedging a percentage of pipeline gas in their portfolios, but should also be limited as to the term of the hedging contracts they can purchase. The limit on the amount LDCs are allowed to hedge should be determined by a scenario that estimates the amount of gas they would need under warmer than normal weather conditions and a high transportation migration scenario, and then discounted by an additional safety margin. Terms should be limited to the next six month CGA period.

5. *What should the core objective of a hedging program be (e.g., least cost, price stability)?*

The Department must determine if a change in the gas cost procurement objective is warranted. The Competitive Suppliers believe that an LDC's objective is to provide least cost supplies to customers that reflect market prices.

6. *How will the Department assess risk-management programs? What benchmarks should be used to measure a risk-management program's performance?*

It would be extremely difficult to assess a risk-management program's performance after the fact. Twenty-twenty hindsight has always been difficult to avoid. Questions of

prudence will exist unless the LDC happens to pick the market low for the year. The only way to assess performance is to design strict guidelines up front, and to measure performance against those guidelines.

7. *What standard of review should the Department apply to the utilities' initial risk management program?*
8. *What types of costs are associated with risk-management? Should LDCs be allowed to recover these costs? If so, please explain how.*

Costs associated with risk management include the cost of the financial instrument, the cost of administration, the costs of systems and the cost of underutilized contracts. The costs of prudently purchased financial instruments as well as all of the other associated costs should be recovered in the LDC's CGA adjustment.

9. *Should an incentive mechanism be used in conjunction with a risk-management program? If so, please explain how this mechanism should be structured.*

The Competitive Suppliers strongly oppose the use of incentives for LDC merchant service. If an LDC desires to be rewarded for gas purchasing, they should set up an unregulated affiliate and compete for customers in the same way that other competitive suppliers compete for customers. Once incentives are introduced to markets that could be competitive, the LDC loses all neutrality with respect to a customer's choice of supplier. Incentives will spell the end of the competitive market.

Rewards without a commensurate level of risk are inconsistent with Department precedent. LDCs bear little to no risk with respect to gas purchasing if they perform in a prudent manner. They are allowed to recover all costs dollar for dollar. They do not

incur the same risks as a competitive supplier. Incentives would tilt the playing field in favor of the utility as the utility has the majority of the customer base, and would no longer have an interest in exiting the merchant function.

IV. CONCLUSION

The Competitive Suppliers believe the Department could allow limited Utility Risk Management Programs. However, any URMP must not distort price signals, must continue to support a least-cost planning objective, must not be allowed to harm the competitive market, and the costs of such a program must be recovered in full in the LDC's Cost of Gas Adjustment. This concludes our comments.

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APPENDIX 1

AllEnergy Gas & Electric Marketing Company, L.L.C. is a wholly owned subsidiary of Exelon Enterprises. AllEnergy provides competitive natural gas service to commercial and industrial customers in the northeastern United States. AllEnergy has been a natural gas supplier in the Commonwealth of Massachusetts since 1996.

Amerada Hess Corporation, through its Energy Marketing Department, provides natural gas supply and related energy services to commercial and industrial customers throughout the Northeast and Middle Atlantic states. Amerada Hess currently serves customers behind all of the gas utilities in Massachusetts.

SCASCO is a wholly-owned subsidiary of Central Hudson Enterprises which in turn is a wholly-owned subsidiary of CH Energy Group. SCASCO provides competitive natural gas service and other forms of energy to customers throughout Connecticut and Massachusetts. SCASCO has been a natural gas supplier in the Commonwealth of Massachusetts since 1999.

Select Energy, Inc. is a wholly owned, competitive energy subsidiary of Connecticut-based Northeast Utilities. Select Energy is a recognized market leader in the electric and natural gas wholesale, retail and energy trading business in the Northeastern United States.

The New Power Company, is the first national provider of electricity and natural gas to residential and small commercial customers in the United States. The Company offers consumers in restructured retail energy markets competitive energy prices, pricing choices, improved customer service and other innovative products, services and incentives.

The National Energy Marketers Association (NEM) is a national, non-profit trade association representing a regionally diverse cross-section of both wholesale and retail marketers of energy and energy-related products, services, information and technology throughout the United States. NEM's membership includes: small regional marketers, large traditional international wholesale and retail energy suppliers (as well as wind and solar power), billing and metering firms, Internet energy providers, energy-related software developers, risk managers, energy brokerage firms, information technology providers as well as suppliers of advanced metering and distributed generation technology. Membership includes both affiliated and unaffiliated companies.